REBUTTAL TESTIMONY OF

JOSEPH M. LYNCH

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2019-226-E

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joseph M. Lynch, and my business address is 220 Operation Way, Cayce, South Carolina.

Q. ARE YOU THE SAME JOSEPH LYNCH THAT OFFERED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to concerns of intervenors regarding the forecast and reserve margin topics presented in my direct testimony.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. The Office of Regulatory Staff ("ORS") retained the services of the consulting firm J. Kennedy and Associates, Inc. to review DESC's IRP and to create a report, "Review of Dominion Energy South Carolina, Inc. 2020 Integrated Resource Plan" ("ORS Report"), which outlines ORS's concerns about the IRP. My rebuttal testimony will go through this report and address the principal concerns related to the forecast and reserve margin. As I address each such concern, I will note whether one of the other intervenors had the same issue. When I finish with the report, certain important concerns of the other intervenors not already addressed in the ORS Report will be addressed. The first part of my rebuttal testimony will address the forecasting process at DESC and the second part, the reserve margin policy.

Q. WILL YOU ADDRESS THE LIST OF CONCERNS SUMMARIZED ON PAGES 4 AND 5 OF THE ORS REPORT?

A. Yes. I will address the concerns summarized on pages 4 and 5 of the ORS Report that pertain to my work as they are discussed in the body of the report.

ISSUES CONCERNING THE FORECAST

Q. ON PAGE 22, THE ORS REPORTS THAT "The Company's energy forecasts appear to have been developed using a reasonable methodology," WHILE ON PAGE 24 IT DISCUSSES HOW SOME UTILITIES USE A STATISTICALLY ADJUSTED END USE ("SAE") MODEL. HAS DESC CONSIDERED USING AN SAE MODEL FOR FORECASTING?

A. Yes. The forecasting team at DESC has discussed using the SAE model but decided against it because of all the unknowns and uncertainties involved. The SAE approach models electric usage based on detailed inputs, many of which are estimated. The results of the model are only as good as the estimates used. The model DESC uses analyzes actual kWh usage by classes or groups of customers and then uses statistical methods to identify what factors explain the changes in that usage over time. It then projects those factors forward to determine what future load would be expected. This is a fact-based approach to load forecasting, while the SAE model requires a high proportion of assumptions to make it work. This can involve a great deal of estimation and approximation, not to say subjectivity.

Q. WHAT SORT OF ASSUMPTIONS ARE INVOLVED IN DEPLOYING THE SAE MODEL?

A. For example, for a residential SAE model you would need to know the square footage of customers' homes, including whether they are single family homes or apartments. You can certainly estimate this information, but there will be a margin of error in doing so. It would be reasonable to assume that every home has air conditioning, but some homes have one central unit, some have two or more central units, and some have window units. For any type of air-conditioning unit, you do not know how many or the SEER rating. Everyone has a refrigerator, but some people have two. Everyone has water heating, but is it electric, or natural gas and how much hot water is used? For example, my teenage children only knew that their morning shower was over when the hot water ran out. I conclude that it is important to know the demographics of who lives in the home. All these things can be estimated, but at the end of the day, the SAE model requires its estimate-based results to be calibrated to the residential actual average kWh use per customer. So, SAE returns to the data, which is where DESC starts.

The forecasting team at DESC believes it is simpler and more accurate to analyze the average kWh use per customer directly using techniques that are statistically valid and well recognized in the industry. This allows DESC to establish co-relationships among load-growth variables and create forecasts based on historical data. DESC believes that this method is preferable to using methods that rely on extensive sets of estimates that must be checked against historical data.

Q. BEGINNING ON PAGE 24 AND CONTINUING THROUGH PAGE 27, THE ORS REPORT MAKES THE POINT THAT GROWTH IN THE RESIDENTIAL AND COMMERCIAL SUMMER AND WINTER PEAK DEMAND FORECAST IS DRIVEN BY THE NUMBER OF CUSTOMERS. ON PAGE 27, THE ORS REPORT DISCUSSES THAT THE INDUSTRIAL PEAK FORECAST USES A LOAD FACTOR METHOD THAT "is a reasonable approach and provides a consistent methodology to both the industrial class energy and peak load forecasts." WHY DID DESC NOT USE A LOAD FACTOR APPROACH TO FORECAST THE RESIDENTIAL AND COMMERCIAL PEAK DEMANDS?

A. First, I want to point out that if you know the number of residential or commercial customers and their kW per customer contribution to peak demand, then the total residential and commercial peak demand can be calculated simply and accurately as the product of these two factors. Calculations based on load factor are not necessary. For these customer classes, DESC forecasts demand using the kW contribution to peak demand per customer, as calculated based on a statistically appropriate analysis of historical data and the number of customers on the system as it grows. DESC uses this approach instead of the load factor approach because it believes it can forecast the total peak demand more accurately using it.

In forecasting the peak demand in the industrial class, the Company uses the load factor approach which ties peak demand to energy sales. Of this approach the ORS says: "This is a reasonable approach and provides a consistent methodology to both the industrial class energy and peak load forecasts." DESC agrees. But DESC does not believe that this approach is accurate for forecasting residential and commercial class loads.

The accuracy of the load factor approach depends on the relationship between energy consumption and contribution to peak demand remaining stable or changing only in predictable ways. That is not necessarily the case today. Since the Great Recession, our residential and commercial customers have been lowering their energy usage by adjusting their thermostats or adding high efficiency appliances or more insulation. However, a large number of our customers use heat pumps or resistance heating, and on a cold winter morning, the heat strips of these customers will come on and will run at capacity, never achieving the required temperature until the peak has passed. On those days, the customers' load will be the same regardless of the thermostat setting. Because of this the relation between peak demand and energy, which the load factor approach depends on, has been changing since the Great Recession in ways that are difficult to predict. Of course, the Company will continue to monitor the data and look for better ways to forecast peak loads. All these matters will be subject to review in future IRPs.

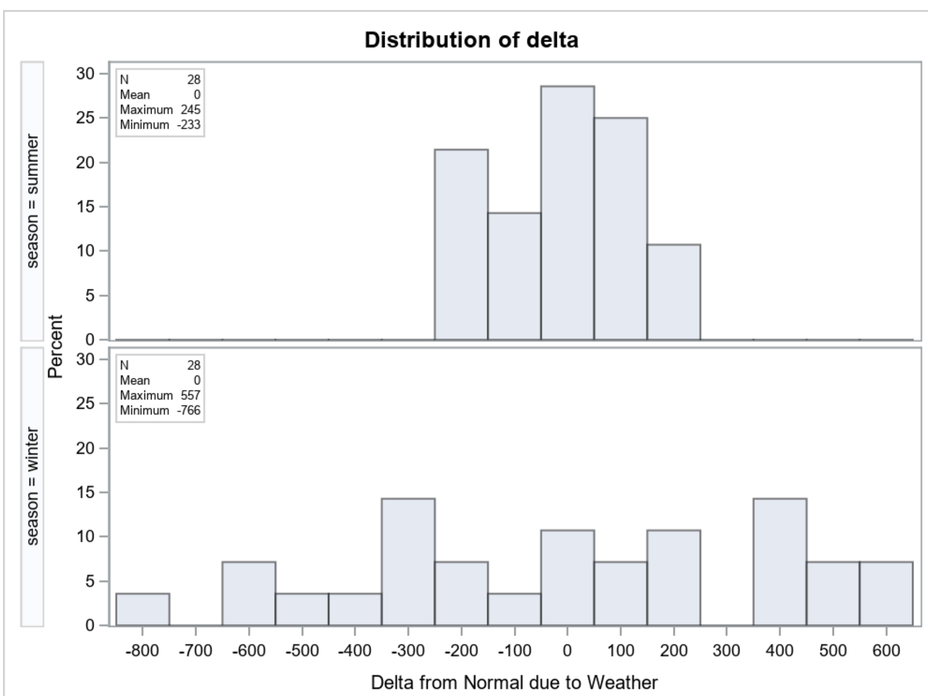
Q. ON PAGE 27, THE ORS REPORT ARGUES THAT "DESC should seek to improve its residential and commercial peak load forecasts to reflect the type of behavioral factors that are likely to impact peak demand over time, such as changes in appliance saturation and appliance efficiency improvements." HOW DO YOU RESPOND?

A. The Company is open to continuing to evaluate this issue, but at this time does not see any discernable benefits from including an additional consideration of behavioral factors in its peak demand calculations. As discussed above, DESC's approach is to base the calculation of per customer contribution to system peak on a statistical analysis of actual data. To the extent that behavioral trends are beginning to emerge in the data, they are captured in this analysis. Behavioral trends that are not part of the data would be accounted for through sensitivity cases. This approach allows DESC to separate data-driven calculations from estimates of the effects of trends not yet present in the data. But if and when a discernible trend appears in the data that can be utilized to project changes in the future, DESC will make the appropriate changes to produce a more accurate forecast.

Q. ON PAGE 29, THE ORS REPORT DISCUSSES THAT DESC'S SUMMER PEAK IN 2019 WAS 4,714 MW WHILE THE FOLLOWING WINTER THE PEAK WAS 4,087 MW. THE ORS REPORT CONCLUDES THAT "This is a significant reversal from recent experience, and is not consistent with the Company's expectations, as shown in its IRP load forecast." HOW DO YOU RESPOND?

A. There is nothing unusual about the relationship between these peaks. This result is mostly caused by weather and is perfectly consistent with DESC's understanding of its system loads and the normal variation in them. The following graph appears on page 9 of my Exhibit No. JML-3, and it shows the relative weather sensitivity of the summer peak to the winter peak.

Graph A: Weather Sensitivity of Winter and Summer Peak



Because of weather fluctuations, DESC expects the deviation from normal in the summer peak to fall in the range defined by a negative 200-300 MW and a positive 200-300 MW. For the winter peak, the range is defined by a negative 800-900 MW and a positive 600-700 MW. DESC's winter peaks are more sensitive to weather and more variable than summer peaks. The results in 2019 are well within the band of expected sensitivity and are not unusual given normal weather fluctuation. In addition, the 2019 results are a single data point. And a single data point is not a trend. For example, the summer peak demand in 2012 was 4,761 MW and the following winter peak was 3,984 MW, which represents a larger decline than in 2019. Despite this, two winters later in 2014/2015, the Company experienced a winter peak demand of 4,970 MW, which is still today the highest ever experienced on the system, summer or winter. Finally, it is worth pointing out that in developing the forecast, the Company is following the data and trends in data that it sees on the system, which were described and presented in my Exhibit No. JML-2. If you follow the data, as DESC does, there is no way to avoid the conclusion that the Company is a winter peaking utility within the range of normal weather variations year to year.

Q. ON PAGES 29 AND 30, THE ORS REPORT STATES THAT DESC CREATED HIGH AND LOW ENERGY AND PEAK SCENARIOS TO COMPLY WITH ACT NO. 62, BUT ORS ALLEGES 1) THAT DESC DID NOT USE ECONOMETRICS TO DERIVE THE HIGH AND LOW

SCENARIOS; 2) THAT THE COMPANY PROVIDED NO DISCUSSION ON HOW THE SCENARIOS WERE CREATED; AND 3) THAT THE USE OF A (PEAK/ENERGY) RATIO TO DERIVE THE PEAK DEMANDS RESULTED IN GROWTH RATES THAT DIFFER FROM THE ENERGY GROWTH RATES. HOW DO YOU REPLY?

A. Regarding the first point, DESC did not use an econometric model to simulate the scenarios because it felt that more realistic scenarios could be formulated by analyzing historical growth rates. These scenarios reasonably reflect the sensitivities they are meant to measure based on actual historical data from the DESC system, adjusted based on the factors driving growth. Regarding the second point, the Company did explain how these growth rates were developed. The explanation begins on page 10 of the IRP. Lastly regarding the difference in peak and energy growth rates, the Company used the peak to energy ratio shown by the data. In the base forecast, the summer and winter peak demands grow about 0.7% per year while energy grows at 0.5%. This spread is maintained in the high and low scenarios. The use of this ratio preserved the relative growth rates of energy and peak demands that were reflected in the base forecast and based on the data.

Q. ON PAGES 30 THROUGH 33, THE ORS REPORT DISCUSSES THAT THE FORECAST SCENARIOS PRESENTED IN THE FIRST SECTION OF THE 2020 IRP WERE NOT USED IN THE ECONOMIC STUDIES OF RESOURCE PLANS PRESENTED LATER IN THE IRP.

FURTHERMORE, ORS ARGUES THAT THE HIGH AND LOW DEMAND SCENARIOS USED IN RESOURCE PLANNING AND DERIVED BY APPLYING A LOW AND HIGH DSM SCENARIOS DO NOT PROVIDE A WIDE ENOUGH DIFFERENCE IN LOAD GROWTH. DO YOU AGREE?

A. ORS suggested that future IRPs should model high and low demand forecasts in addition to DSM forecasts and a wider range of demand forecasts generally. The Company intends to consider this request and implement changes in the future as appropriate to provide the wider, requested range. That said, it is true that the forecast scenarios presented in the first section of the IRP were not used later in the economic analyses. There were eight different forecast scenarios presented: the base forecast, a high and a low economic growth scenario, a wholesale scenario and three electric vehicle saturation scenarios, which could result in 18 separate combinations of sensitivities for economic growth. The intent of these scenarios was to show various risks to the forecast as required by Act No. 62 under Section 58-37-40(B)(1)(a). DESC believed that to include all eight forecast scenarios or 18 additional sensitivities in the economic analysis of resource plans would produce too many scenarios making it unreasonably difficult to draw meaningful conclusions from the study.

ORS recognizes that DESC's resource planning scenarios do include high and low demand/energy scenarios based on DSM assumptions that show the effect on the resource plans of low and high load growth. ORS believes that in future

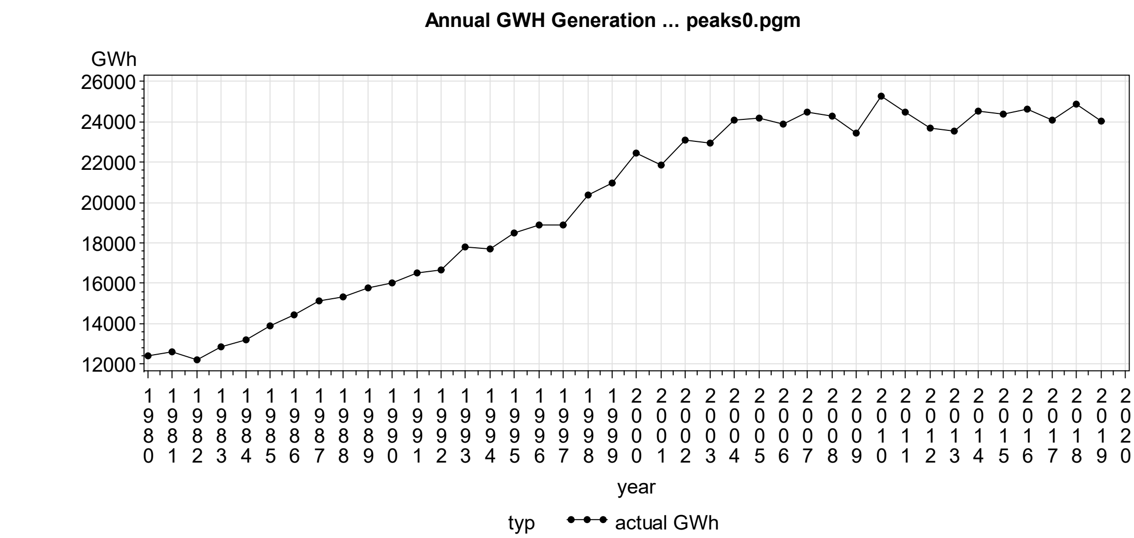
IRPs the resulting spread between the high and low loads should be wider. DESC is receptive to the recommendation that a wider band of forecasted demands may be appropriate in future cases but believes that the spread used in this IRP is wide enough to allow an appropriate evaluation of the potential impact of higher or lower demand/energy growth on the eight resource plans.

Q. SIERRA CLUB WITNESS MR. STENCLIK DISCUSSES ON PAGE 17[1] THAT DESC'S FORECAST HAS BEEN TOO HIGH SINCE 2006. CAN YOU EXPLAIN?

A. Yes. The following graph shows that from 1980 to 2007, the DESC's system energy grew at a very predictable rate of about 2.5% per year. Since the Great Recession of 2008-2009, growth has leveled off and has been much lower and less consistent. In the face of 27 years of experience with steady growth around 2.5%, it was a natural assumption to expect a return of growth after the recession. Therefore, any forecast made prior to the Great Recession and for several years after would be too high. I believe you would see the same result for most utilities in the country.

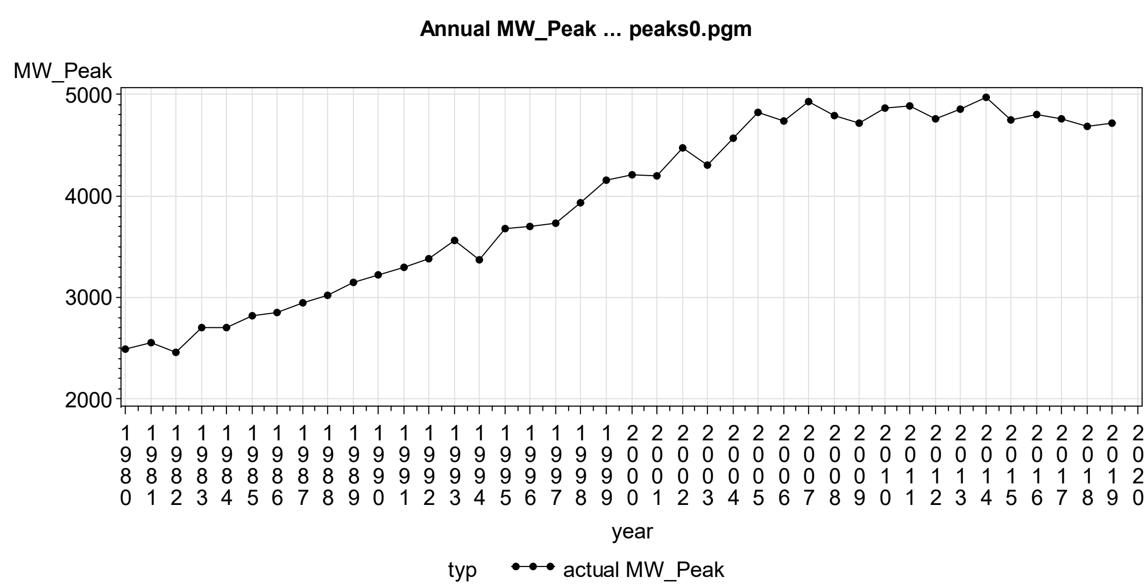
[1] References to page numbers are to page numbers of that witness's direct testimony.

Graph B: DESC's System Energy Growth



Similar statements can be made when referencing the system peak demand. Graph C shows the historical system peak demands. Like the system energy, the peaks grew about 2.5% from 1980 through 2007 and then basically leveled off.

Graph C: DESC's System Peak Demands



Q. ON PAGE 18 MR. STENCLIK OPINES THAT "The likely economic recession following COVID-19 could make for long-term load reductions lasting years." DO YOU AGREE?

A. No. The following table shows the Company's estimate of the COVID impact on weather normalized monthly generation.

Table A: COVID Impact on Monthly Generation

2020 Month	% Reduction
March	-3.4
April	-12.7
May	-5.4
June	-3.4
July	-2.0
August (Estimate as of August 21)	-1.1

The COVID impact peaked in April and has been steadily decreasing since then. Based on the data, the Company believes the COVID impact on sales will largely end before the end of the year.

Q. ON PAGE 20 MR. STENCLIK SUGGESTS THAT THE WINTER PEAK FORECAST IS TOO HIGH BECAUSE "the IRP assumed a load factor of 0.56, which is significantly lower (6.7%) than recent observations." DO YOU AGREE?

A. No, I do not. First, DESC does not assume a load factor. The load factor is the result of the forecast, which is based on factual data, projected forward based on economic and customer growth factors, among other things. Also, Mr. Stenclik calculates the winter load factor of 56.0% using the 2020 winter gross peak. If he used the 2020 winter firm peak demand, the resulting load factor would be 58.7%. Furthermore, over the last 40 years, the system experienced a high load factor of 60.9% and a low of 54.3% with a median of 57.8%. Thus, Mr. Stenclik's 56.0% load factor, which he considers low, and the 58.7% load factor based on firm peak demand, which he ignores, both fall within the range of historical system experience. Finally, if DESC restricts consideration of years when the system peaked in the winter season, then the range of winter load factors was a high of 60.0% to a low of 55.4% with a median value of 56.7%. Based on these historical ranges, the winter load factor resulting from the Company's forecast is entirely consistent with actual data and is reasonable.

Q. ON PAGES 24 AND 25 OF HIS DIRECT TESTIMONY, SACE WITNESS MR. HILL OBSERVES THAT THE COMPANY'S FORECAST WORKBOOK SHOWS ZERO ENERGY EFFICIENCY ("EE") IMPACTS IN YEARS 2020 AND 2021 AND THAT THE ACCUMULATED EE IMPACTS REPORTED IN THE COMPANY'S POTENTIAL STUDY DIFFER FROM THOSE REPORTED IN THE FORECAST WORKBOOK, FOR EXAMPLE, ONE SHOWS 327 GWH INSTEAD OF 499 GWH IN 2024 AND AGAIN 430 GWH IN 2025 INSTEAD OF 498 GWH. CAN YOU EXPLAIN THESE DIFFERENCES?

A. Yes, I can. Below is a table showing the annual (row 1) and accumulated (row 2) EE impacts of the Company's programs under the medium, or base case, scenario.

Table B: Energy Efficiency Impacts

		Energy Efficiency (EE) Impacts (MWh)					
		2020	2021	2022	2023	2024	2025
1	**Medium - DSM Potential Study**	77,362	94,556	106,755	108,967	111,332	103,509
2	**Accumulated**	77,362	171,918	278,673	387,640	498,971	602,480
3	**Incremental Impact on Forecast**	0	0	106,755	215,722	327,053	430,562

The accumulated EE impact in 2024 is 498,971 MWh. This is the 498 GWh and 499 GWh numbers that Mr. Hill is looking for, with one being rounded down and the other rounded up. The Company's short-term forecast covering the next two years by month is heavily dependent of statistical trend models. Since these models pick up trends in recent data, the forecasting team believes the forecast produced by these models already includes the EE impacts. In particular, the sales forecast for 2020 and 2021 already includes the 77,362 MWh in 2020 and 94,556 MWh in 2021 of EE impacts shown in the medium DSM scenario. Therefore, when you look at 2024, the underlying sales forecast contains 171,918 MWh of accumulated EE impacts which, with the addition of the incremental EE impact of 327,053 MWh, produces the total EE impact of 498,971 MWh that Mr. Hill was expecting.

REGARDING THE RESERVE MARGIN POLICY

Q. ON PAGE 33, THE ORS REPORT CONCLUDES THAT "the overall finding is that the primary peaking reserve margins for the summer and winter peak periods of 14% and 21%, respectively, are reasonable." DO YOU AGREE?

A. Yes, I do.

Q. ON PAGE 34 ORS ACKNOWLEDGES THAT DESC USES A "BUILDING BLOCK APPROACH" TO DEVELOP ITS RESERVE MARGIN BUT LATER CRITICIZES THE METHODOLOGY. CAN YOU JUSTIFY THE BUILDING BLOCK APPROACH?

A. Yes. The building block methodology is logical and understandable. It reflects the three reasons that DESC needs planning reserves. These are the three building blocks around which the reserve margin is set. They are:

1) VACAR Reserves: DESC is a member of the VACAR Reserve Sharing Group which requires DESC, unless prevented by a system emergency, to always have about 200 MW in reserve and available in 15 minutes to support the combined transmission systems of DESC, DEVa, DEC, DEP and Santee Cooper. The purpose of these reserves does not include support for the normal, day-to-day operations of the DESC system. Therefore, DESC must plan on always having on hand about 200 MW of capacity to respond to emergencies anywhere within the VACAR group.

2) Supply-side Risk: Each year DESC attests to the Southeastern Electric Reliably Council ("SERC") the net capacity of its generating units. However, it almost never has that amount of capacity available to serve load. There are many moving parts on the system, and there is almost always an amount of capacity either forced out or de-rated. The average daily capacity forced out is 200 MW, and the Company has used this as the level of unreliable capacity for more than 40 years of maintenance planning, finding it very appropriate over this period of time. For the winter and summer peak seasons analyzed for the reserve margin, the Company chose a slightly higher level of 223 MW in winter and 234 MW in summer. This reflects the fact that weather conditions can affect the ability of generating units to produce full capacity under extreme conditions. To use the full capacity ratings of its generating units would be unreasonable and irresponsible. In planning, the dependable level of capacity should be used.

3) Demand-side risk: Like most electric utilities, DESC projects its winter and summer peak demands based on normal weather, which means the actual peak demands will be higher in half the years. This implies the need to add reserve capacity for when the weather is above normal. But how much to add? Using statistical analysis, DESC determined that the increase in winter peak demand will be greater than 531 MW in one out of 10 winters, *i.e.,* 10% of the years, and maybe as high as 557 MW or higher. Since this interval range is small, only 26 MW, and subject to a statistical margin of error, DESC uses the high end of the interval for

its winter demand side risk. Using similar logic, DESC uses 245 MW for its summer demand side risk.

Q. ORS SUGGESTED THAT IN FUTURE IRPs THE COMPANY SHOULD PROVIDE FURTHER JUSTIFICATION FOR ITS TREATMENT OF VACAR RESERVE CAPACITY IN ITS RESERVE PLANNING. CAN YOU EXPLAIN HOW THE VACAR AGREEMENT WORKS?

A. Yes. The VACAR Reserve Sharing Agreement requires DESC to carry approximately 200 MW of capacity in reserve at all times. The precise amount varies from year to year based on annual calculations, but in the current context it is always close to 200 MW. This amount, along with the amounts held in reserve by other VACAR members, allows VACAR to maintain its collective reserve obligation. The SERC and the North American Electric Reliability Council ("NERC") require VACAR at all times to have reserves sufficient to respond to the most severe single contingency on its members' combined system. This is typically the loss of the generation from the largest single generator on the VACAR system.

The Company's 200 MW of VACAR reserves are a subset of the Company's operating reserves in the sense that DESC must be able to identify 200 MW among the reserve units available on its system at all times that can be used to support VACAR reserve requirements. This capacity must be available in 15 minutes to support the loss of a generator within the VACAR system. Which units will provide the 200 MW of reserves devoted to VACAR requirements does not have to be explicitly identified, but the units comprising this 200 MW amount of capacity cannot be used to serve load at the same time they are being counted as VACAR reserves.

If system conditions change due to loss of solar, loss of units, un-forecasted weather changes, loss of transmission, or other changes, and DESC is not carrying its VACAR reserves, it is obligated to contact other VACAR members to see if another member has extra reserves sufficient to make up for DESC's shortfall so that VACAR can maintain its reserve obligation without DESC's required contribution. If the answer is yes, then the VACAR reserve requirements are satisfied and no further action is required. If the answer is no, or becomes no later in the day, then DESC must declare an Energy Emergence Alert ("EEA") Level 1 notifying the VACAR Reliability Coordinator and Reserve Sharing Group that the group is not carrying the required contingency reserves because of DESC's shortfall.

While in an EEA 1, if DESC is still generation deficient, DESC enters an EEA level 2 and initiates its Emergency Energy and Capacity Procedure (SOP-700) which means curtailing all non-firm load, making appeals to the public, and employing all methods available to alleviate the problem including voltage reductions. Once all the steps outlined in SOP-700 have been implemented, excluding curtailing firm load, DESC can request the members of the VACAR Group to provide capacity to it from the remaining VACAR reserves. After calling on VACAR for reserves, DESC has 12 hours or until the following midnight, whichever is later, to supply its own needs and restore its 200 MW VACAR reserve commitment.

If emergency capacity from VACAR or purchased capacity from other sources is not available, then DESC must declare an EEA Level 3. At that point firm load must be curtailed to maintain voltage and frequency on the system, *i.e.,* rolling blackouts. If at any point in this process, DESC cannot balance its load through its own resources or actions, through purchases, through reserves it can call on from other VACAR members, or through rolling blackouts, its neighboring utilities may open their tie lines to prevent cascading outages beyond the DESC balancing area. This would isolate DESC from the Eastern Interconnection and can cause a DESC system-wide collapse.

If DESC does not plan its system to fulfill its obligation to VACAR, it runs the risk of being expelled from the reserve sharing agreement going forward. In that case, SERC and NERC would require DESC to carry enough reserves at all times to cover its single most severe contingency, which currently is no less than 660 MW. This requirement is backed by fines and enforcement actions under FERC authority.

Q. ON PAGE 34 ORS EXPRESSES A CONCERN WITH DESC'S RESERVE MARGIN POLICY, STATING "The immediate concern with this policy is that it is not strictly a reliability-based criterion, but instead an economic

criteria. Ordinarily, an expansion planning model is used to determine the type and timing of adding new capacity." DO YOU AGREE?

A. No. DESC, like all utilities, uses a planning model to analyze the trade-off between capital costs and operating costs of potential new generating resources. This trade-off exists because building a more efficient generating unit with lower variable production cost generally requires the utility to spend additional capital dollars, which can offset the savings in variable production costs. The more efficient unit must run a sufficient number of hours so that its more efficient variable production costs offset its higher capital cost. For example, a combined cycle plant will have a higher capital cost than a combustion turbine, but if it is required to operate enough hours in serving the load, the lower variable production costs may justify the added capital costs. However, DESC is winter peaking and can experience a significant spike in load every five years or so. Clearly a peaking resource is needed for these infrequent events, and the savings in variable production costs will not be sufficient to justify the additional capital costs of a baseload resource since there will not be enough energy generated. It would not be in customers' interest for DESC to add baseload generation resources to meet short-duration load spikes to the extent that peaking or demand response resources could meet these needs. It has been the Company's experience that this approach works well to avoid costlier alternatives. Moreover, DESC consistently monitors markets and can change our approach if required. And as ORS requests, the

Company does plan to implement a least cost optimization model in the next IRP update if this is practical. These issues will be revisited in that implementation process.

Q. CAN DESC ENSURE AN OPTIMUM OVERALL RESOURCE PLAN IF IT ANALYZES THE BASE RESOURCES SEPARATELY FROM THE PEAKING RESOURCE NEEDS?

A. Yes. DESC considers the choice of an optimum ***base*** resource plan as a separate resource problem from that of choosing an optimum ***peaking*** resource plan. When DESC finds an optimal resource mix for its base needs and a separate one for its peaking needs, then its overall resource plan will be optimized. This approach works well because the base and peaking needs are sufficiently different given the short-duration nature of winter peaks. But once again, this issue will be revisited with the implementation of resource optimization software discussed above.

Q. HOW CAN DESC CONSIDER THE RESOURCE PLANNING ISSUE AS TWO SEPARATE OPTIMIZATION PROBLEMS WHEN THE RESOURCES OF ONE KIND CAN MEET THE NEEDS OF THE OTHER KIND?

A. DESC does not believe that base and peaking resources are interchangeable. Peaking resources are expected to operate for a few days of the year and likely only a few days every few years when the weather is abnormal. These peaking resources are time-limited and cannot replace base resources that are required to operate most of the year. It is true that a combustion turbine can serve as this sort of peaking resource, but this approach is not cost competitive with demand response and short-term capacity purchases. DESC sees no need to burden customers with additional costs of a generating plant if that can be avoided. Also, in the current IRP resource plans, the short-term capacity purchases are considered place holders and leave a place in the plan for expanded DR options like those that will become available with the rollout of AMI.

Q. ON PAGE 21 OF HIS DIRECT TESTIMONY SCSBA WITNESS MR. SERCY CLAIMS THAT "This approach effectively excludes hundreds of MWs from the IRP process where candidate resource plans are modeled and compared to one another" AND THAT 21% SHOULD BE USED TO CALCULATE AVOIDED COSTS. DO YOU AGREE?

A. This is not correct. Hundreds of MWs are not being excluded from the IRP process. The Company has a two-step process. The first step is a traditional resource planning exercise that finds the lowest cost resources balancing energy production variable costs against fixed capital costs for base system needs. The second step is to find the lowest cost source of peaking capacity, a step in which the variable production costs of energy are essentially irrelevant. The source of the peaking capacity can be short-term purchases; additional DR, including additional DR made available through AMI, among other things; or upgrades to existing peaking resources. These are the resources that can best meet that need at much lower cost than base capacity resources. To plan the system to require a 21% reserve margin to be supplied by base capacity resources would risk burdening customers with unnecessary costs.

Q. ON PAGE 18 OF HIS DIRECT TESTIMONY SCSBA WITNESS MR. SERCY CLAIMS THAT IN COMMISSION ORDER 2020-244 ON PAGES 9-11 THAT "the PSC adopted an 11.8% capacity value for solar PV that recognizes a modest year-round capacity value for incremental solar on the DESC system." DO YOU AGREE?

A. No, I do not. The 11.8% is based on a year-round capacity value to be used in establishing avoided capacity costs for solar in the design of avoided cost rates. The Commission did not order the Company to assume 11.8% of nameplate solar capacity would be available to serve the winter peak demand, which occurs before sunrise, nor did the Commission order the Company to reduce the 46% solar contribution to summer peak demand it assumes for existing solar PPAs. It would be irresponsible for the Company to assume that solar PV could make an 11.8% contribution to winter peak when as a matter of engineering it would not be able to do so. Mr. Sercy clearly misunderstands the Commission's intent.

Q. ON PAGE 37, THE ORS REPORT ARGUES THAT FOR THE PEAK DEMAND RISK DESC IS USING THE WORST WEATHER IN THE STUDY RESULTING IN A 1-IN-28 YEAR EVENT RATHER THAN USING

A PROBABILISTIC MEASURE ON THE ENTIRE WEATHER DISTRIBUTION. HOW DO YOU RESPOND?

A. On page 10 of my Exhibit No. JML-2, in Table 2 and reproduced as Table C below, I show the upper part of the weather distribution of loads by season. Since DESC is winter peaking, I focus here on the winter distribution. The 90th percentile in that weather distribution is 531 MW, which means that in 10% of the winter seasons, the winter peak demand will be greater than the normal level by between 531 and 557 MW. That range of 531 MW to 557 MW is only 26 MW, which is a small difference and may not be statistically significantly different. Therefore, I chose the upper value in this 10% range and consider the occurrence of this very cold weather to be a 1-in-10-year event.

Table C: Weather Distribution of Loads by Season

MW Weather Deviations by Percentile				
Percentile	**75%**	**90%**	**95%**	**100%**
Summer	**118**	**173**	**214**	**245**
Winter	**380**	**531**	**554**	**557**

Q. EVEN IF THERE IS A 1-IN-10 CHANCE OF A VERY COLD WINTER WITH INCREASES IN PEAK DEMAND IN THE RANGE OF 531 TO 557 MW, SHOULDN'T THE 10% PROBABILITY OF THIS OCCURRENCE BE USED TO DISCOUNT THE LEVEL OF RISK AND DECREASE THE RESERVE MARGIN?

A. That approach would not be prudent. While the expected value for the number of very cold winters is 0.1, *i.e.,* an occurrence of one in ten years, this 10% probability means that there is a 79.4% probability that there will be at least one or more of these very cold winters occurring in the IRP planning horizon, *i.e.,* over the next 15 years. DESC's dispatchers do not think about "if" such a winter will occur; they know it is only a question of "when." When this very cold winter does occur, DESC wants to have sufficient resources available to serve the load reliably. Using the binomial probability distribution, the following table was developed.

Table D: Probability of At Least The Number of Occurrences in 15 Years
Binomial Probability Distribution with Parameter p=10%

At Least	Probability
1 Occurrence	79.4%
2 Occurrences	45.1%
3 Occurrences	18.4%

The table shows that there is a large enough probability of a very cold winter occurring at least once, twice or even three times or more in the planning horizon, so the Company must plan for this event.

Q. ON PAGE 38 ORS DISCUSSES THAT DESC DOES NOT COMPARE THE SUPPLY COST OF RESERVES TO THE VALUE OF LOST LOAD ("VOLL") TO DERIVE AN ECONOMICALLY OPTIMUM RESERVE MARGIN. WHY DID DESC NOT DO THIS ANALYSIS?

A. DESC does not believe such an analysis will produce useful results because the VOLL is a very uncertain number. It should always be greater than the monetary loss of an outage and should include an added amount representing customer inconvenience, disruption and frustration of customers' expectations of reliable service. Customers want their lights to stay on, particularly when it is freezing cold and dark outside. The cost of rolling blackouts during cold winter mornings is not easily calculated in economic terms. ORS reports that while Duke performs this analysis, it does not rely on it to set its reserve margin. And that seems reasonable. It is not a calculation that should be used for resource planning decisions. DESC uses statistical analysis and probability theory to measure the risk of an outage and then uses its experience operating the system and management judgement to set its reserve margin policy all the while keeping in mind that the VOLL, though unquantified, is a very large number.

Q. ON PAGE 38, THE ORS REPORT DISCUSSES THE COMPANY'S SUPPLY SIDE OF RISK AND CONSTRUCTS TABLE 8 TO SHOW DIFFERENT CHOICES OF RESERVE MARGIN THE COMPANY COULD HAVE CHOSEN. WAS THIS METHOD HOW DESC CHOSE ITS RESERVE MARGIN?

A. No. First, when selecting a level of supply risk, it is important to realize that on most of the days of the year, the Company does not have the full capacity of all of its units available. Each unit has a forced outage rate associated with it that quantifies the unit's average available capacity throughout the year. Planning without considering these forced outage rates is not appropriate or reasonable. As I discussed earlier, for 40 or more years, the Company has had a rule of thumb that 200 MW of its capacity should be considered unreliable for planning purposes, and this rule of thumb has proven to be very appropriate and reasonable over this period of time. This 200 MW is the average amount of capacity that is forced out or rerated each day. Each year in scheduling unit maintenance, the Company calculates the residual level of reserves after the peak load is served and the scheduled capacity is subtracted. Two quantities have always been calculated: Book Reserves and Reliable Reserves. The difference between the two is 200 MW, the amount of unreliable capacity. In reserve margin vernacular, this 200 MW is considered to be the average daily supply risk on the system and has been for the last 40 or more years. In the reserve margin study attached to my testimony as Exhibit No. JML-3, the probability distribution of supply risk during the two peak seasons was reported and is reproduced in Table E.

Table E: MW Forced Out by Percentile

Percentile	50%	60%	70%	80%	90%	100%
Summer	106	152	234	385	618	1,402
Winter	121	165	223	373	520	1,552

Management has chosen a level of supply risk for the peak seasons that is slightly higher than the average daily outage of 200 MW, *i.e.,* 234 MW for summer and

223 MW for winter. Additionally, these levels of 234 MW and 223 MW representing the 70th percentile in the distribution of daily seasonal outages are also turning points in these distributions, that is to say, the cost of having additional reserves to cover the next 10 percentage points will be about 2.5 times the previous in the winter distribution and about 1.8 times in the summer. So setting the supply-side risk at a level reflecting the 70th percentile of risk is appropriate and reasonable.

Q. ON PAGE 39 ORS SEEMS TO QUESTION THE INCLUSION OF THE VACAR RESERVE SHARING MW IN THE CALCULATION OF RESERVE MARGIN, ARGUING THAT THE VACAR RESERVES ARE OPERATING RESERVES FOR DAY TO DAY OPERATION OF THE SYSTEM AS OPPOSED TO A RESOURCE PLANNING REQUIREMENT. HOW DO YOU RESPOND?

A. The VACAR reserves are not used in the normal day to day system operations to help dispatchers follow the load and maintain frequency and voltage. The VACAR reserves are there to protect the reliability of the VACAR system and are not used unless justified by a system emergency. They are not part of normal operations. When DESC signed the VACAR Agreement, it agreed to maintain about 200 MW in ready reserves every minute of the day, every day of the year. Thus, under normal operations DESC must have sufficient capacity to serve its customers' load and have another 200 MW available in 15 minutes.

Q. ON PAGE 40 ORS CLAIMS THAT THE COMPANY'S LOSS OF LOAD EXPECTATION ("LOLE") STUDY PROVIDED IN DISCOVERY DERIVED A MINIMUM WINTER RESERVE MARGIN BETWEEN 17% AND 18% AND NOTED THAT THIS WAS CLOSE TO DUKE ENERGY'S RESERVE MARGIN. DO YOU AGREE?

A. No, I do not. I have included the Company's LOLE Study as Exhibit No.____(JML-4). The following table summarizing the results of the study shows the range of reserve margins under 30 different load profiles with the LOLE set to the industry guidance of 0.1 days per year.

Table F: LOLE Study Results

Reserve Margin Methodology	Minimum	Median	Maximum
Peak Adjustment Methodology	16.6%	18.2%	20.5%
Energy Adjustment Methodology	14.8%	17.2%	21.3%

The 30 resulting reserve margins producing an LOLE=0.1 per year ranges from a low of 14.8% to a high of 21.3%. These results are based on normal weather. If abnormal weather conditions were introduced, the range would be greater.

Q. ON PAGE 43 ORS RECOMMENDS THAT DESC CONSIDER THE IMPACT OF "varying weather conditions." HAS DESC DONE SO?

A. Yes. This was done through the weather driven peak demand spike that I included in an LOLE analysis. In the LOLE study, I calculated the impact of a 500 MW spike in peak load on the LOLE reliability index and then calculated how much more capacity would have to be added to restore the system to the same level of reliability, *i.e.,* produce the same LOLE value. Below is the table showing the results of the study.

Table G: Experiment to Analyze Peak Load Increase and Risk

	Peak Load	Capacity	LOLE
Step 1: Calculate base value of LOLE	4,964	5,900	0.11235
Step 2: Add 500 MW to peak day	5,464	5,900	0.23616
Step 3: Increase Capacity to Restore LOLE	5,464	6,095	0.11234

The LOLE methodology equates the increase in risk related to a 500 MW spike in peak demand with the reduction in risk related to an increase of 195 MW in capacity. This result is at least counter-intuitive and makes me believe that the LOLE methodology is ill suited for a winter peaking utility subject to spikes in load.

Q. HOW CAN THE LOLE METHODOLOGY EQUATE THE INCREASE IN SYSTEM RISK ASSOCIATED WITH A 500 MW SPIKE IN LOAD TO THE DECREASE IN RISK ASSOCIATED WITH THE ADDITION OF ONLY 195 MW OF CAPACITY?

A. The LOLE for the year is the summation of a daily LOLE calculation on each of the 365 days of the year. When the 500 MW spike in load is added to the peak day, only the LOLE calculation for that day changes. The peak demands on the other 364 days of the year do not change. When 195 MW of capacity is added to the fleet of resources, the LOLE calculation changes on every day of the year to reflect the additional capacity that now is available. So even though 195 MW is not sufficient to cover the new winter peak, the LOLE calculation ignores that fact because it determines that the increase in reliability on the other 364 days of the year offsets that deficiency. But it is precisely on peak days where the regional system is stressed and the risks and consequences of not meeting load are greatest. In short, the LOLE methodology obscures the most important consideration: What resources are needed to reliably meet winter peaks?

Q. WHAT IS THE IMPACT OF THIS 500 MW SPIKE ON THE RANGE OF RESERVE MARGINS BASED ON LOLE?

A. According to the LOLE methodology, the 500 MW spike results in the need for an additional 195 MW of capacity, which is about a 3.6% increase in reserve margin. Adding this increase to the range based on normal weather produces the following table:

Table H: LOLE Study Results with 500 MW Spike

Reserve Margin Methodology	Minimum	Median	Maximum
Peak Adjustment Methodology	20.2%	21.8%	24.1%
Energy Adjustment Methodology	18.4%	20.8%	24.9%

In a very cold winter, the range of reserve margins using the LOLE=0.1 criterion is 18.4% to 24.9%.

Q. DO THE RESULTS OF THE COMPANY'S LOLE STUDY SUPPORT THE COMPANY'S RESERVE MARGIN?

A. Yes, they do. Each calculation of an LOLE value requires an annual load profile comprised of 365 daily peak demands. In the Company's LOLE study, thirty different load profiles were developed based on an actual, historical system load profile. Thirty reserve margins were derived that produced an LOLE of 0.1, *i.e.* that meet the one day in 10-year standard. Finally, the impact of a 500 MW spike was added to the results producing another 30 reserve margins associated with an LOLE=0.1. The range of reserve margins with an LOLE=0.1 resulting from these 60 different load profiles was a low of 14.8% to a high of 24.9%. The Company's winter peak reserve margin of 21% falls within that range.

Q. SIERRA CLUB WITNESS MR. STENCLIK RECOMMENDS ON PAGE 36 OF HIS DIRECT TESTIMONY THAT "The Commission should open a docket specifically related to reserve margin requirements and resource adequacy analysis." DO YOU AGREE?

A. No, I do not. The reserve margin issue is part of the integrated resource planning process and is properly addressed in that venue. To open a separate docket to address the reserve margin is not necessary. In my direct testimony I explained the Company's reserve margin policy and how it is formulated. As Mr. Bell testified, the Company will be revisiting its reserve margin policy as it implements the new resource optimization approach to resource planning. If changes are required, they will be proposed as a part of that process and brought before this Commission in future proceedings. Finally, I reiterate the conclusion of the ORS stated on page 33 of the ORS Report that "the overall finding is that the primary peaking reserve margins for the summer and winter peak periods of 14% and 21%, respectively, are reasonable."

CONCLUSION

Q. IN CONSIDERATION OF YOUR REBUTTAL TESTIMONY, WHAT ARE YOU ASKING THE COMMISSION TO DO?

A. Based on all of the points I have made above, I am asking the Commission to adopt ORS's position that the reserve margins and load forecasts the Company used in the 2020 IRP were appropriate and acceptable. While the Company and ORS believe that the current range of load forecasts was adequate, nonetheless the Company is willing to discuss with all stakeholders the possibility of expanding the range of load forecasts in future proceedings. Additionally, the Company will reevaluate load forecasts and reserve margins in light of the implementation of the resource optimization model in future proceedings. However, for purposes of this proceeding, the Commission should accept the reserve margins and load forecasts the Company used in the 2020 IRP.

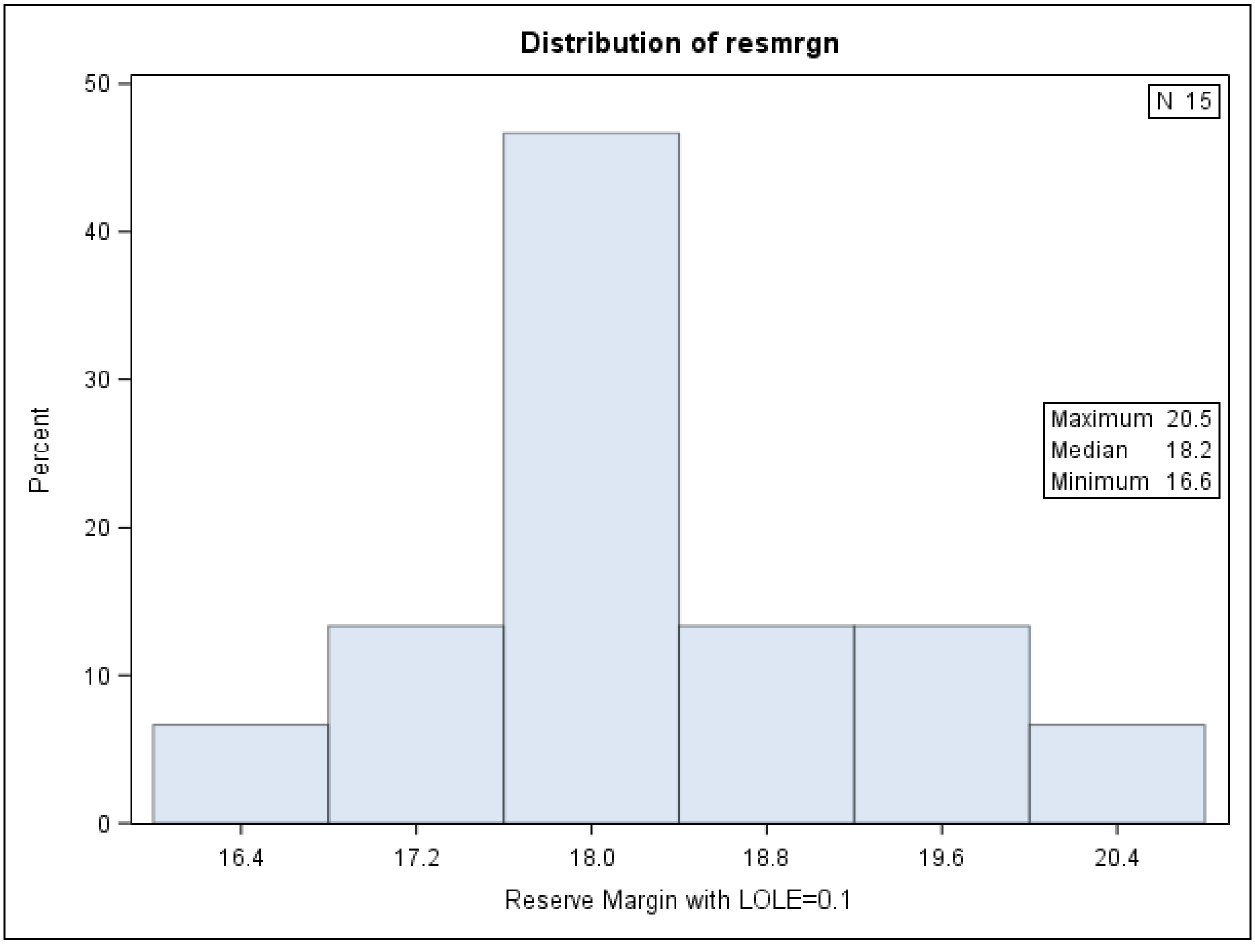
Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Loss of Load Expectation Study

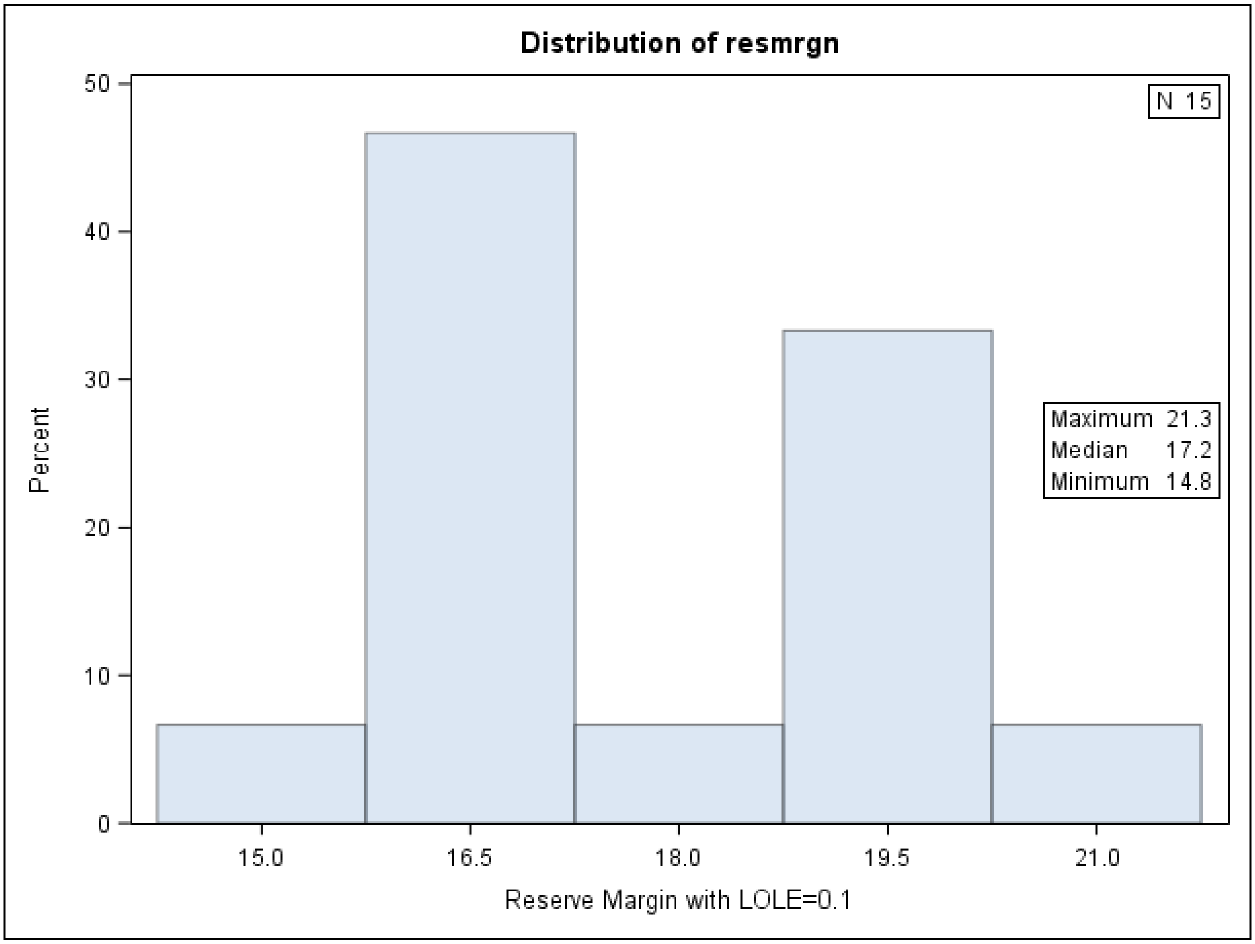
Executive Summary

The Loss of Load Expectation ("LOLE") reliability index was calculated using the adjusted profiles from the last 15 years, 2004-2018. The goal of the study was to calculate the relationship on Dominion Energy South Carolina, Inc.'s ("DESC") system between reserve margin and LOLE, thereby deriving the reserve margin equivalent to an LOLE=0.1. Two studies were run: one using an adjustment based on seasonal peaks, the "peak" method, and a second using an adjustment based on energy, the "energy" method. The following histogram summarize the results when using the peak method.



This histogram reflects that a reserve margin between 16.6% and 20.5% is required to achieve reliability at the level represented by an LOLE=0.1, i.e., one day in 10 years. The average, or middle point, in the distribution is 18.2%.

The following histogram summarizes the results when using the energy method.



This histogram reflects that a reserve margin between 14.8% and 21.3% is required to achieve reliability at the level represented by an LOLE=0.1, i.e., one day in 10 years. The average, or middle point, in the distribution is 17.2%.

Since the LOLE index represents reliability for the entire year and is calculated using peak loads on each day of the year, it should be used to evaluate DESC's base reserve margin policy, i.e., having a minimum reserve margin of 14% throughout the winter season and 12% throughout the summer season. As explained later in this report, it is not appropriate to use LOLE to assess risk during extreme weather events. Using the LOLE methodology, a 14% reserve margin equates to about an LOLE=0.3, i.e., 3 days in 10 years. However, DESC mitigates much of this apparent risk, i.e., 0.3 vs 0.1 LOLE, by its use of peaking reserves which are expected to be available for a few peak days each season.

Introduction

The LOLE methodology essentially consists of three steps: 1) prepare the normalized daily peak load data; 2) calculate the capacity outage probability table ("COPT") which associates a probability to a level of outage; and 3) using the daily peaks and the COPT compute the expected number of days of outage, i.e., the LOLE index. The industry standard for reliability sets the LOLE at 0.1 which equates to an expectation of 1 day of outage every 10 years and is known as the "1 in 10" criterion.

It is worth noting that the term loss of load probability ("LOLP") is often used interchangeably with LOLE although strictly speaking LOLP is a probability and LOLE is an expected value.

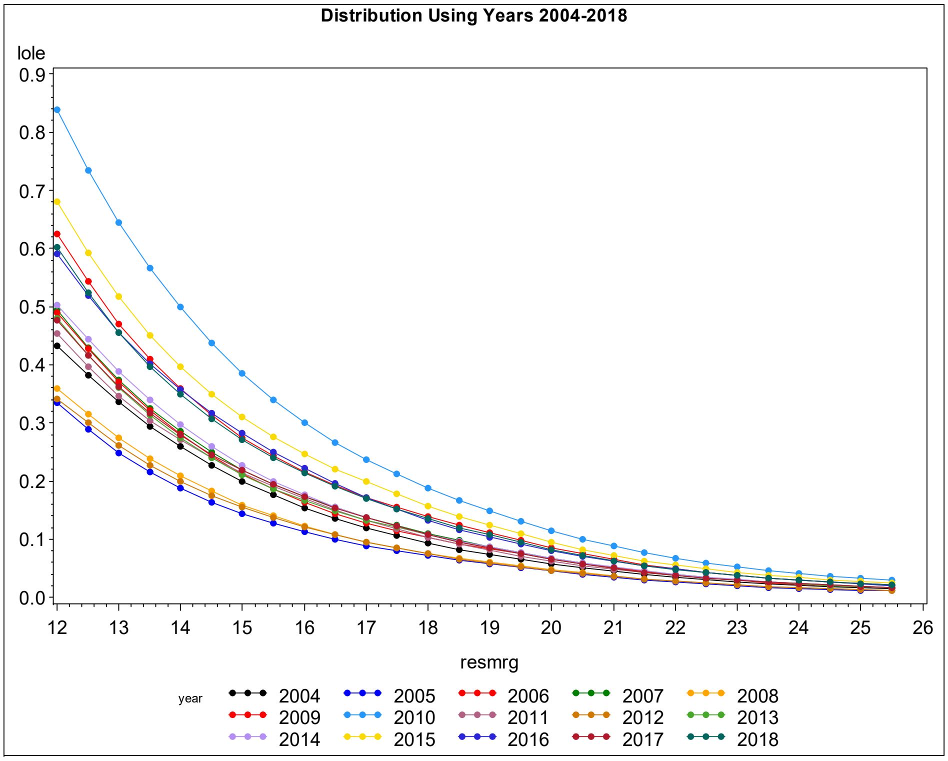
The Details

The daily peak load data was calculated for each of the last 15 years, i.e., 2004 through 2018, under two adjustment scenarios. The first type of adjustment, the "peak" method, adjusted the daily loads from history so that their summer and winter peaks were equal to those projected for 2019, that is, the adjustment factor for daily peaks in the summer months was the ratio of the 2019 summer peak over the historical years summer peak and a similar adjustment for winter months using winter peaks. The second method, the "energy" method, adjusted historical daily peaks by the ratio of the 2019 forecasted system energy by the system energy occurring in the historical year. Summary results of these adjustments are shown in Table 1 of the appendix.

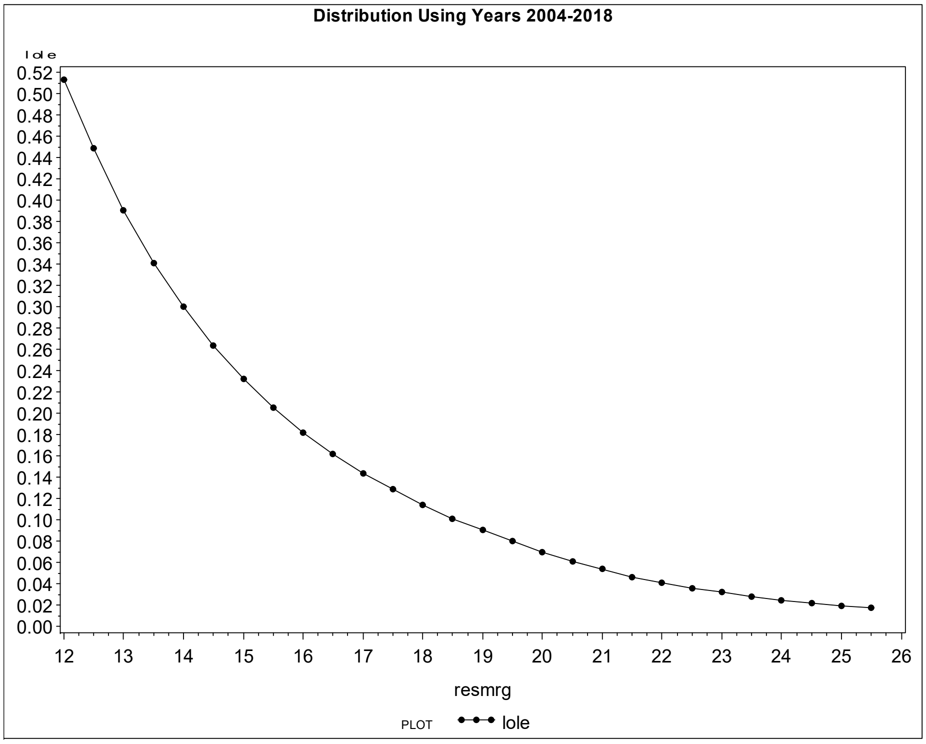
The COPT was calculated from the Company's forced outage data for the years 2010 through 2017. The forced outage rate of each generating unit was calculated and then averaged over the 8 years. The result was the effective forced outage rate, ("EFOR"), from which the COPT was created. A few small gas turbines ("GT") did not have acceptable data and their EFOR was set to 5%. Each unit is considered either available or unavailable with the probability of being unavailable equal to the EFOR. Thus, the outage status of each unit can be described by a binomial probability distribution with parameter EFOR. In this way a total of 65 binomial distributions are set up, one for each unit. To create the COPT, these probability distributions are combined using the convolution algorithm from statistical theory. The convolution algorithm requires the individual probability distributions to be statistically independent. For the most part generating units are mechanically independent, but their availability is not statistically independent since several units can be affected simultaneously by severe weather or fuel restrictions. Nevertheless, the COPT is calculated under the assumption that this independence technicality has minor influence. A summary version of the COPT table is shown as Table 2 in the appendix.

The next step was to use the daily peak loads from each year, one year at a time, and the COPT to calculate the LOLE index. Since the goal was to establish a relationship between reserve margin and LOLE on the DESC system, the LOLE was calculated using values of reserve margin ranging from 12% to 25% in 0.5% steps. Thus, the LOLE associated with 28 different values of reserve margin was computed for each year from 2004 to 2018. The results of these calculations are shown in Tables 3 and 4 in the appendix.

The following graph shows the relationship between reserve margin on the horizontal and the LOLE index shown on the vertical for each year in the study. This graph is for the "peak method" of adjustment. The graph for the "energy method" of adjustment would look similar.



The following graph shows the average LOLE value for each reserve margin level.



The functional relationship between LOLE and reserve margin is not linear but the relationship between the LOG(LOLE) and reserve margin is linear. The logarithm function, LOG( ), used here is the natural logarithm, i.e., with the transcendental number "e" for base. Below are the results of fitting this functional form to the data.

The REG Procedure
Model: MODEL1
Dependent Variable: resmrg

Number of Observations Read	29
Number of Observations Used	28
Number of Observations with Missing Values	1

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	456.62783	456.62783	97176.7	<.0001
Error	26	0.12217	0.00470		
Corrected Total	27	456.75000			

Root MSE	0.06855	R-Square	0.9997
Dependent Mean	18.75000	Adj R-Sq	0.9997
Coeff Var	0.36559		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	9.23069	0.03317	278.28	<.0001
lnlole	1	-4.01300	0.01287	-311.73	<.0001

The parameter estimates in the function can be used to calculate the reserve margin level associated with an LOLE=0.1. Here are the calculations:

$$\begin{aligned}\text{Reserve Margin} &= a + b * \text{LOG(LOLE)} \\ &= 9.23069 - 4.01300 * \text{LOG}\ (0.1) \\ &= 9.23069 - 4.01300 * (-2.30259) \\ &= 18.5\end{aligned}$$

Thus, based on the average LOLE data, an LOLE value of 0.1 requires about an 18.5% reserve margin. The equation can also be used to find the LOLE for a given reserve margin by reversing the solution process. For example, it is easy to show that DESC's base winter reserve margin level of 14% is associated with an LOLE=0.3 or about a 3 day in 10 LOLE level.

This same analysis using the average LOLE value for each reserve margin level can be made for the "energy method" of adjustment. The regression results are as follows:

The REG Procedure
Model: MODEL1
Dependent Variable: resmrg

Number of Observations Read	29
Number of Observations Used	28
Number of Observations with Missing Values	1

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	456.63099	456.63099	99755.9	<.0001
Error	26	0.11901	0.00458		
Corrected Total	27	456.75000			

Root MSE	0.06766	R-Square	0.9997
Dependent Mean	18.75000	Adj R-Sq	0.9997
Coeff Var	0.36084		

Parameter Estimates

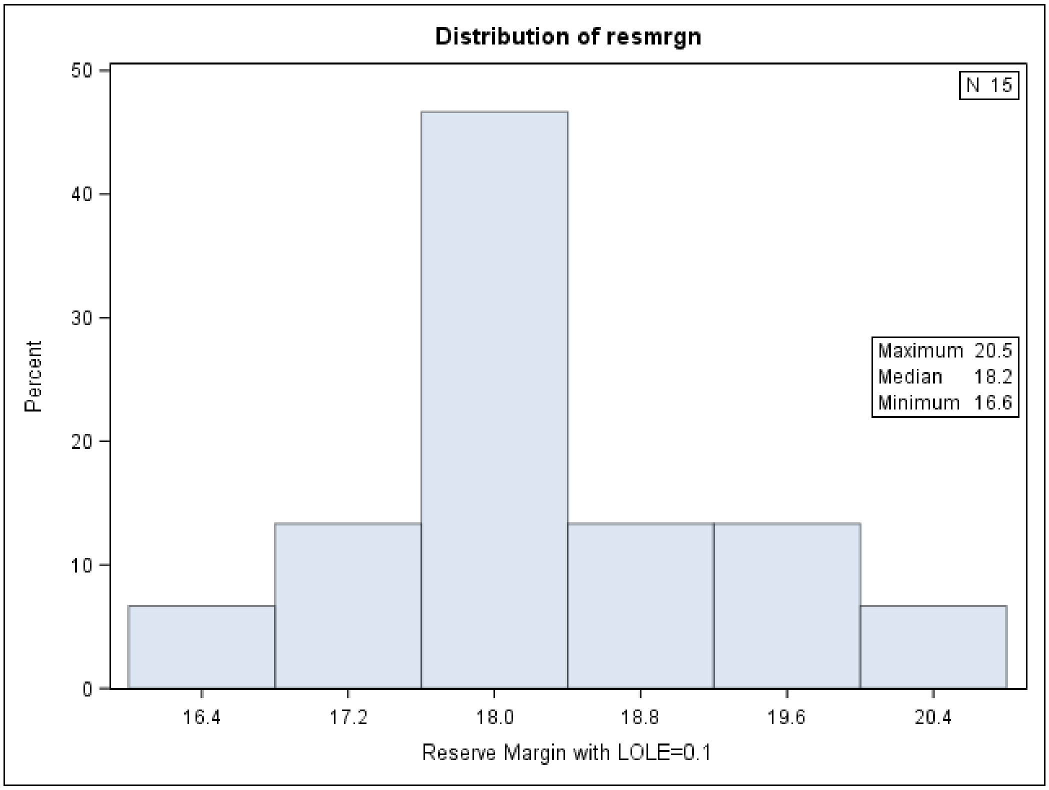
Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	8.84337	0.03387	261.08	<.0001
lnlole	1	-4.00696	0.01269	-315.84	<.0001

The parameter estimates in the function can be used to calculate the reserve margin level associated with an LOLE=0.1. The calculations are as follows:

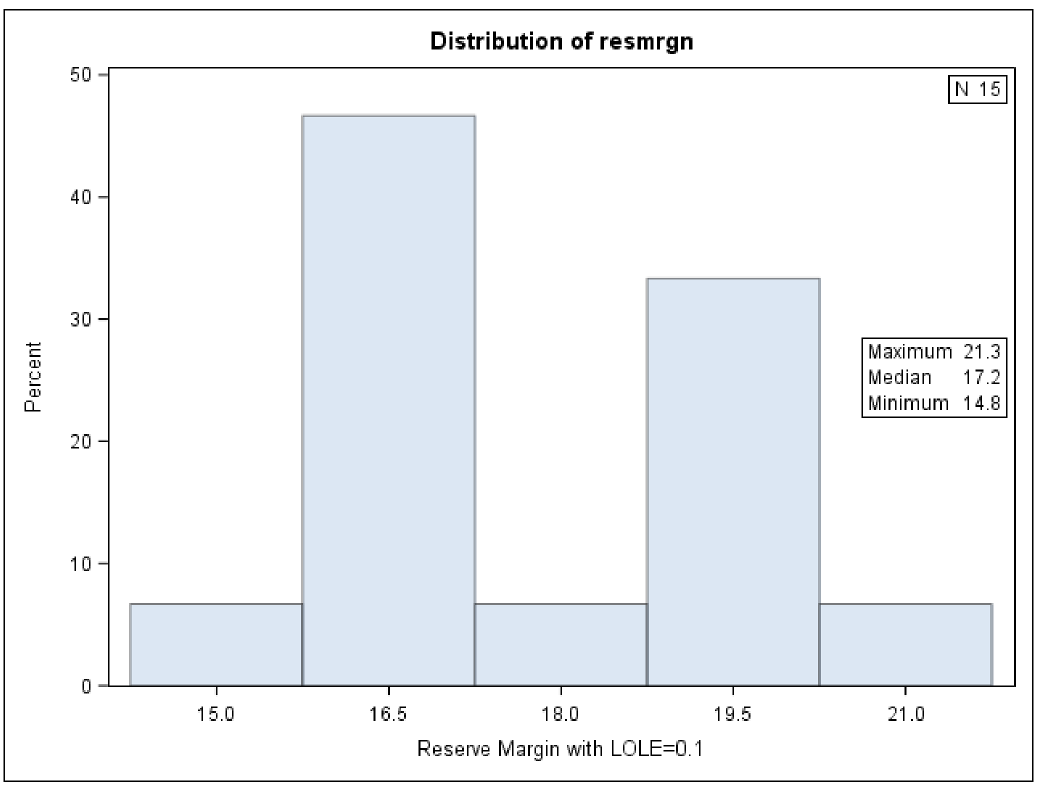
Reserve Margin = a + b * LOG(LOLE)
= 8.84337 – 4.00696 * LOG (0.1)
= 8.84337 – 4.00696 * (-2.30259)
= 18.1

Thus, based on the average LOLE data, an LOLE value of 0.1 requires about an 18.1% reserve margin. The equation can also be used to find the LOLE for a given reserve margin by reversing the solution process. For example, it is easy to show that DESC's base winter reserve margin level of 14% is associated with an LOLE=0.3 or again about a 3 day in 10 LOLE level.

The same log-linear function can be estimated for each year in the study under both the peak method of adjustment and the energy method of adjustment. Once the equations are estimated, their parameters can be used to solve for the reserve margin level associated with an LOLE of 0.1 just as demonstrated above. The following histogram shows the distribution of results for the peak method.



The following histogram shows the results under the energy method of adjustment.



LOLE and the Risk Analysis of Extreme Peaks

The LOLE index may be useful as a measure of the average risk on a system over the entire year but it does not address the risk from peak demands that spike up under severe weather conditions. This can be demonstrated through a simple experiment involving three steps. The first step is to run the LOLE analysis for a year and note the LOLE value. Step two simulates a spike in load on the peak day. Since DESC is concerned with a winter spike in load of around 500 MW, this experiment will increase the peak load by 500. Then the LOLE analysis is run again on the modified load data and the LOLE value is noted. The resulting LOLE value is higher than in step one indicating increased risk over the year. In step 3, the amount of capacity is increased to a level that restores the LOLE value to its original value under step one. The increase in capacity over step one reflects the amount required to offset the increase in risk caused by the spike in peak demand according to LOLE theory.

DESC conducted the experiment described above using the adjusted 2018 load data and a 500 MW spike in peak load. The results of this experiment are summarizedin the following table.

Experiment to Analyze Peak Load Increase and Risk			
	Peak Load	**Capacity**	**LOLE**
Step 1: Calculate base value of LOLE	**4,964**	**5,900**	**0.11235**
Step 2: Add 500 MW to peak day	**5,464**	**5,900**	**0.23616**
Step 3: Increase Capacity to Restore LOLE	**5,464**	**6,095**	**0.11234**

The LOLE results suggest that an increase of 195 MW in capacity (=6,095-5,900) is sufficient to offset the increase in risk caused by a 500 MW spike in load (=5,464-4,964). This does not seem reasonable. However, the LOLE methodology arrives at this conclusion because it is measuring risk for the entire year and the capacity increase of 195 MW makes every day in the year a little less risky so much so that the unacceptable risk on the peak day is completely offset by the sum of these daily increases.

APPENDIX

Table 1 Annual Summary Information for Adjusted Historical Profiles

"The Energy Method" Historical Profiles Adjusted to 2019 Energy

year	maxmw	summwh
2004	4,532	23,864,178
2005	4,758	23,864,178
2006	4,737	23,864,178
2007	4,803	23,864,178
2008	4,702	23,864,178
2009	4,642	23,864,178
2010	4,471	23,864,178
2011	4,757	23,864,178
2012	4,796	23,864,178
2013	4,636	23,864,178
2014	4,722	23,864,178
2015	4,867	23,864,178
2016	4,658	23,864,178
2017	4,650	23,864,178
2018	4,558	23,864,178

"The Peak Method" Historical Profiles Adjusted to 2019 Seasonal Peak Demands

year	smr_ maxmw	wtr_ maxmw	summwh
2004	4,911	4,964	27,419,072
2005	4,911	4,964	25,821,068
2006	4,911	4,964	26,985,458
2007	4,911	4,964	26,816,776
2008	4,911	4,964	25,576,498
2009	4,911	4,964	25,407,442
2010	4,911	4,964	26,390,123
2011	4,911	4,964	24,798,622
2012	4,911	4,964	25,497,702
2013	4,911	4,964	27,185,234
2014	4,911	4,964	25,686,071
2015	4,911	4,964	24,800,039
2016	4,911	4,964	26,329,200
2017	4,911	4,964	25,951,274
2018	4,911	4,964	25,890,877

Table 2 Capacity Outage Probability Table (“COPT”)

Note: LOLP represents the cumulative probability. For example, from the table the probability of 100 MW or more being forced out is about 48.32% while for 900 MW, it’s 1.35%.

MW Out	LOLP	MW Out	LOLP	MW Out	LOLP
0	1.0000	530	0.0928	1600	0.0002
10	0.9342	540	0.0902	1700	0.0001
20	0.8588	550	0.0879	1800	0.0000
30	0.8044	560	0.0861	1900	0.0000
40	0.7463	570	0.0844	2000	0.0000
50	0.6969	580	0.0828	2100	0.0000
60	0.6493	590	0.0813	2200	0.0000
70	0.6113	600	0.0798	2300	0.0000
80	0.5670	610	0.0784	2400	0.0000
90	0.5231	620	0.0739	2500	0.0000
100	0.4832	630	0.0691	2600	0.0000
110	0.4497	640	0.0655	2700	0.0000
120	0.4261	650	0.0618	2800	0.0000
130	0.4010	660	0.0586	2900	0.0000
140	0.3803	670	0.0547	3000	0.0000
150	0.3620	680	0.0510	3100	0.0000
160	0.3483	690	0.0472	3200	0.0000
170	0.3358	700	0.0436	3300	0.0000
180	0.3199	710	0.0404	3400	0.0000
190	0.3072	720	0.0375	3500	0.0000
200	0.2946	730	0.0352	3600	0.0000
210	0.2841	740	0.0329	3700	0.0000
220	0.2744	750	0.0308	3800	0.0000
230	0.2663	760	0.0287	3900	0.0000
240	0.2587	770	0.0270	4000	0.0000
250	0.2509	780	0.0253	4100	0.0000
260	0.2432	790	0.0237	4200	0.0000
270	0.2362	800	0.0223	4300	0.0000
280	0.2309	810	0.0210	4400	0.0000
290	0.2262	820	0.0199	4500	0.0000
300	0.2220	830	0.0189	4600	0.0000
310	0.2182	840	0.0178	4700	0.0000
320	0.2151	850	0.0169	4800	0.0000
330	0.2124	860	0.0161	4900	0.0000
340	0.2099	870	0.0153	5000	0.0000
350	0.2017	880	0.0146	5100	0.0000
360	0.1927	890	0.0140	5200	0.0000
370	0.1842	900	0.0135	5300	0.0000
380	0.1761	910	0.0130	5400	0.0000
390	0.1705	920	0.0126	5500	0.0000
400	0.1643	930	0.0122	5600	0.0000
410	0.1573	940	0.0119	5700	0.0000
420	0.1483	950	0.0116	5800	0.0000
430	0.1413	960	0.0110	5900	0.0000
440	0.1330	970	0.0104		
450	0.1260	980	0.0099		
460	0.1202	990	0.0094		
470	0.1149	1000	0.0090		
480	0.1105	1100	0.0042		
490	0.1061	1200	0.0022		
500	0.1023	1300	0.0013		
510	0.0990	1400	0.0006		
520	0.0958	1500	0.0003		

Table 3 LOLE Index by Reserve Margin Based on the "Peak Method" of Adjustment

resmrg	_2004	_2005	_2006	_2007	_2008	_2009	_2010	_2011
12.0	0.43304	0.33493	0.62506	0.49446	0.35865	0.48997	0.83839	0.45379
12.5	0.38234	0.28952	0.54329	0.43004	0.31434	0.42833	0.73506	0.39627
13.0	0.33579	0.24906	0.47080	0.37403	0.27465	0.37130	0.64482	0.34655
13.5	0.29427	0.21524	0.40965	0.32541	0.23864	0.32148	0.56614	0.30450
14.0	0.25945	0.18814	0.35898	0.28510	0.20909	0.28084	0.49862	0.27099
14.5	0.22773	0.16403	0.31291	0.24937	0.18232	0.24306	0.43714	0.24048
15.0	0.19996	0.14384	0.27486	0.21966	0.15906	0.21196	0.38459	0.21339
15.5	0.17568	0.12679	0.24355	0.19491	0.13993	0.18567	0.33983	0.19098
16.0	0.15441	0.11227	0.21634	0.17372	0.12290	0.16291	0.30107	0.17029
16.5	0.13568	0.09938	0.19270	0.15497	0.10799	0.14351	0.26625	0.15038
17.0	0.11934	0.08851	0.17207	0.13810	0.09560	0.12756	0.23707	0.13313
17.5	0.10555	0.07983	0.15480	0.12416	0.08519	0.11502	0.21279	0.11820
18.0	0.09296	0.07167	0.13861	0.11035	0.07558	0.10297	0.18781	0.10352
18.5	0.08209	0.06410	0.12357	0.09739	0.06721	0.09244	0.16592	0.09087
19.0	0.07391	0.05802	0.11111	0.08749	0.06078	0.08396	0.14894	0.08126
19.5	0.06554	0.05169	0.09799	0.07714	0.05409	0.07458	0.13103	0.07128
20.0	0.05784	0.04539	0.08579	0.06728	0.04766	0.06578	0.11438	0.06211
20.5	0.05115	0.03956	0.07476	0.05872	0.04194	0.05798	0.10023	0.05441
21.0	0.04541	0.03469	0.06558	0.05162	0.03704	0.05088	0.08837	0.04816
21.5	0.03935	0.02986	0.05648	0.04460	0.03197	0.04389	0.07692	0.04207
22.0	0.03466	0.02608	0.04945	0.03922	0.02806	0.03839	0.06781	0.03737
22.5	0.03064	0.02290	0.04340	0.03455	0.02467	0.03348	0.05980	0.03310
23.0	0.02702	0.01995	0.03807	0.03043	0.02158	0.02921	0.05265	0.02921
23.5	0.02368	0.01740	0.03347	0.02683	0.01882	0.02549	0.04628	0.02578
24.0	0.02087	0.01544	0.02987	0.02391	0.01663	0.02254	0.04115	0.02305
24.5	0.01836	0.01370	0.02664	0.02125	0.01467	0.01990	0.03648	0.02043
25.0	0.01628	0.01223	0.02381	0.01889	0.01304	0.01769	0.03249	0.01814
25.5	0.01452	0.01099	0.02140	0.01688	0.01164	0.01590	0.02902	0.01617

resmrg	_2012	_2013	_2014	_2015	_2016	_2017	_2018
12.0	0.34195	0.47973	0.50334	0.68108	0.59148	0.47691	0.60222
12.5	0.29966	0.41645	0.44353	0.59311	0.51914	0.41560	0.52399
13.0	0.26082	0.36145	0.38897	0.51658	0.45567	0.36194	0.45509
13.5	0.22690	0.31301	0.33929	0.45024	0.40182	0.31619	0.39603
14.0	0.19992	0.27391	0.29755	0.39668	0.35717	0.27895	0.34868
14.5	0.17554	0.23941	0.25920	0.34994	0.31687	0.24577	0.30656
15.0	0.15492	0.21057	0.22644	0.30979	0.28188	0.21875	0.27134
15.5	0.13721	0.18673	0.19922	0.27610	0.25044	0.19479	0.24061
16.0	0.12178	0.16605	0.17604	0.24680	0.22174	0.17309	0.21397
16.5	0.10773	0.14804	0.15529	0.22118	0.19539	0.15444	0.19091
17.0	0.09539	0.13315	0.13729	0.19884	0.17194	0.13755	0.17067
17.5	0.08499	0.12083	0.12224	0.17871	0.15189	0.12279	0.15283
18.0	0.07510	0.10732	0.10825	0.15769	0.13273	0.10798	0.13558
18.5	0.06636	0.09521	0.09596	0.13974	0.11612	0.09488	0.11990
19.0	0.05970	0.08596	0.08641	0.12508	0.10348	0.08500	0.10756
19.5	0.05282	0.07554	0.07654	0.10919	0.09103	0.07486	0.09461
20.0	0.04635	0.06568	0.06726	0.09460	0.07975	0.06513	0.08234
20.5	0.04084	0.05736	0.05926	0.08252	0.07026	0.05697	0.07183
21.0	0.03604	0.05022	0.05239	0.07242	0.06244	0.05020	0.06297
21.5	0.03114	0.04315	0.04539	0.06268	0.05464	0.04343	0.05441
22.0	0.02742	0.03774	0.03978	0.05523	0.04853	0.03821	0.04792
22.5	0.02429	0.03320	0.03498	0.04891	0.04311	0.03378	0.04234
23.0	0.02141	0.02927	0.03073	0.04334	0.03819	0.02991	0.03734
23.5	0.01875	0.02582	0.02694	0.03824	0.03359	0.02647	0.03281
24.0	0.01662	0.02293	0.02385	0.03406	0.02979	0.02358	0.02920
24.5	0.01465	0.02039	0.02107	0.03040	0.02631	0.02086	0.02603
25.0	0.01301	0.01830	0.01868	0.02729	0.02330	0.01862	0.02338
25.5	0.01162	0.01656	0.01668	0.02454	0.02071	0.01674	0.02094

Table 4 LOLE Index by Reserve Margin Based on the "Energy Method" of Adjustment

resmrg	_2004	_2005	_2006	_2007	_2008	_2009	_2010	_2011
12.0	0.29226	0.27686	0.46937	0.37424	0.37084	0.57333	1.04027	0.59745
12.5	0.25781	0.24348	0.40882	0.32623	0.32538	0.50346	0.91209	0.52065
13.0	0.22587	0.21116	0.35660	0.28759	0.28646	0.44189	0.79405	0.44877
13.5	0.19849	0.18237	0.30852	0.25069	0.25061	0.38121	0.69132	0.38656
14.0	0.17449	0.15778	0.26912	0.21984	0.22108	0.33125	0.60640	0.34001
14.5	0.15279	0.13840	0.23629	0.19330	0.19472	0.28873	0.53515	0.30082
15.0	0.13478	0.12105	0.20799	0.17042	0.17105	0.25093	0.47095	0.26634
15.5	0.11819	0.10705	0.18208	0.14913	0.15117	0.21842	0.41459	0.23882
16.0	0.10349	0.09510	0.16150	0.13151	0.13256	0.19121	0.36917	0.21311
16.5	0.09128	0.08465	0.14290	0.11640	0.11685	0.16736	0.32648	0.19115
17.0	0.08036	0.07508	0.12686	0.10361	0.10242	0.14794	0.29007	0.17233
17.5	0.07035	0.06714	0.11360	0.09235	0.09040	0.13154	0.25950	0.15329
18.0	0.06245	0.05917	0.10174	0.08258	0.07997	0.11813	0.23035	0.13646
18.5	0.05527	0.05246	0.09068	0.07359	0.07076	0.10696	0.20583	0.12126
19.0	0.04902	0.04715	0.08089	0.06592	0.06284	0.09665	0.18357	0.10816
19.5	0.04339	0.04144	0.07225	0.05866	0.05519	0.08642	0.16144	0.09409
20.0	0.03858	0.03645	0.06346	0.05129	0.04901	0.07700	0.14256	0.08244
20.5	0.03399	0.03215	0.05575	0.04520	0.04322	0.06871	0.12592	0.07209
21.0	0.03004	0.02826	0.04905	0.03952	0.03826	0.05976	0.11022	0.06279
21.5	0.02662	0.02449	0.04266	0.03464	0.03365	0.05210	0.09588	0.05458
22.0	0.02324	0.02142	0.03701	0.03016	0.02963	0.04553	0.08401	0.04785
22.5	0.02037	0.01871	0.03249	0.02647	0.02593	0.03948	0.07385	0.04192
23.0	0.01807	0.01646	0.02840	0.02352	0.02276	0.03440	0.06504	0.03717
23.5	0.01593	0.01448	0.02498	0.02071	0.02010	0.03014	0.05751	0.03311
24.0	0.01393	0.01314	0.02214	0.01825	0.01774	0.02646	0.05108	0.02906
24.5	0.01234	0.01144	0.01940	0.01616	0.01562	0.02324	0.04516	0.02647
25.0	0.01089	0.01009	0.01765	0.01450	0.01378	0.02067	0.04013	0.02360
25.5	0.00965	0.00897	0.01565	0.01293	0.01248	0.01832	0.03577	0.02114

resmrg	_2012	_2013	_2014	_2015	_2016	_2017	_2018
12.0	0.36312	0.27772	0.21390	0.31315	0.61847	0.55622	0.67135
12.5	0.31640	0.24410	0.18773	0.27953	0.53751	0.48258	0.58840
13.0	0.27804	0.21059	0.16401	0.24748	0.47098	0.42163	0.50893
13.5	0.24092	0.18198	0.14117	0.21822	0.41044	0.36520	0.44279
14.0	0.21091	0.15843	0.12199	0.19151	0.36065	0.32005	0.39064
14.5	0.18544	0.13714	0.10532	0.16994	0.32024	0.28051	0.34284
15.0	0.16342	0.12047	0.09156	0.14794	0.28384	0.24857	0.30292
15.5	0.14489	0.10550	0.07972	0.12813	0.25354	0.22082	0.27042
16.0	0.12929	0.09362	0.06970	0.11102	0.22724	0.19688	0.24002
16.5	0.11518	0.08392	0.06092	0.09710	0.20343	0.17686	0.21370
17.0	0.10310	0.07538	0.05395	0.08428	0.18037	0.15723	0.19195
17.5	0.09167	0.06724	0.04780	0.07384	0.15995	0.14018	0.17022
18.0	0.08209	0.06016	0.04280	0.06534	0.14167	0.12551	0.15198
18.5	0.07224	0.05382	0.03849	0.05840	0.12386	0.11142	0.13484
19.0	0.06387	0.04805	0.03461	0.05205	0.10964	0.09894	0.11951
19.5	0.05628	0.04225	0.03114	0.04652	0.09580	0.08692	0.10528
20.0	0.04945	0.03739	0.02756	0.04124	0.08369	0.07635	0.09206
20.5	0.04316	0.03257	0.02445	0.03680	0.07310	0.06677	0.08070
21.0	0.03787	0.02853	0.02150	0.03268	0.06404	0.05850	0.07032
21.5	0.03308	0.02473	0.01866	0.02917	0.05663	0.05072	0.06119
22.0	0.02897	0.02153	0.01621	0.02557	0.04960	0.04460	0.05369
22.5	0.02546	0.01899	0.01421	0.02226	0.04372	0.03902	0.04747
23.0	0.02213	0.01649	0.01227	0.01959	0.03904	0.03424	0.04180
23.5	0.02008	0.01446	0.01076	0.01718	0.03463	0.03031	0.03691
24.0	0.01780	0.01289	0.00937	0.01493	0.03094	0.02702	0.03276
24.5	0.01582	0.01148	0.00824	0.01309	0.02746	0.02403	0.02916
25.0	0.01404	0.01026	0.00749	0.01153	0.02441	0.02147	0.02624
25.5	0.01246	0.00907	0.00652	0.01022	0.02153	0.01922	0.02323